SURREBUTTAL TESTIMONY OF

Dr. Ben Johnson

ON BEHALF OF THE

SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

Before the

PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2018-2-E

Introduction

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida.

Q. HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE AND SCOPE OF THIS TESTIMONY?

A. I am responding to the rebuttal testimony of Joseph M. Lynch, on behalf of South Carolina Electric & Gas Company ("SCE&G" or the "Company") concerning the proposed rates to be paid to Qualified Facilities ("QF"). I focus almost exclusively on pages 34-46 of his testimony – his response to my direct testimony. My failure to comment on other parts of Mr. Lynch's testimony should not be construed as agreement with the statements he makes, or the conclusions he reaches in those parts of his testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I've largely followed the same sequence used by Dr. Lynch.

Q. IS IT FAIR TO CHARACTERIZE CHANGES PROPOSED BY SCE&G IN THIS PROCEEDING AS "DRAMATIC"?

A. Yes. Dr. Lynch disagrees with the conclusion reached by Brian Horii, testifying on behalf of the Office of Regulatory Staff ("ORS"), that SCE&G is implementing a "dramatic change in approach" in this proceeding.[1] Yet, his only basis for disagreeing is his vague claim that the Company is still "using the same difference in revenue requirements ("DRR") methodology previously approved by the Commission." In reality, the DRR

1 Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, Page 2.

method is simply one of three broadly accepted methods for estimating avoided costs. Numerous methodological details determine how the DRR method is implemented. The Company has undertaken a “dramatic change in approach” in how it is implementing the DRR method. These changes have not been fully identified, nor has there been an opportunity to fully investigate and analyze them.

The Company should not be given a *carte blanche* to make changes to its methodology, merely because it claims the revised methodology stays within the broad boundaries of the DRR method. To the contrary, all changes to its methodology, including changes to its expansion planning model, should be fully disclosed and explained, and the parties should be given an adequate opportunity to investigate and respond to those changes – and to propose alternative changes of their own.

Significantly, Dr. Lynch does not claim the version of the DRR method the Company used in this case is identical to the version approved in past proceedings. In fact, a close comparison of the workpapers provided in this proceeding (particularly the ones related to its avoided capacity costs) with the analogous workpapers provided in past proceedings suggests there are many significant differences. While there hasn't been an opportunity to fully examine those differences, they clearly are of sufficient magnitude and significance to justify the description that a “dramatic change in approach” has been proposed by the Company in this proceeding. These changes go far beyond merely updating inputs within the context of the previously approved methodology – something that could have been accomplished by simply updating some of the cells contained in the workpapers the Company used in preparing last year's filing.

It was simply not feasible for the parties to fully investigate and analyze these dramatic changes to the Company's approach – including changes to the expansion planning model and related changes to the generation expansion plan – within the time constraints applicable to this proceeding. The Company had many months to develop its proposals, and it gained additional time when it obtained permission to postpone its QF rate filing from December 2017 until February 2018. In contrast, the non-Company parties were provided less than 45 days to examine the Company's QF rate proposals and supporting workpapers, and to prepare their responsive testimony.

Last year, I noted that the fuel proceeding is not the "ideal forum" for fully exploring and resolving some of the policy concerns and methodological issues affecting QF rates. That observation remains true, and the need for more time to work through the details of the QF-related issues is even more apparent given the "dramatic changes" in approach being proposed by the Company.

Q. THIS PROCEEDING CONTAINS HUNDREDS OF PAGES OF TESTIMONY. ARE YOU SUGGESTING THERE WASN'T AN ADEQUATE OPPORTUNITY TO INVESTIGATE AND DISCUSS THE QF ISSUES?

A. Yes. I realize this is counter-intuitive, given the sheer volume of material filed by the parties. In reality, some QF issues have been discussed extensively, while others have barely been touched.

In a typical rate case, or in complex corporate litigation involving highly technical, complex issues like the ones being dealt with here, the schedule would provide an opportunity for the parties to engage in multiple rounds of discovery, including follow-up questions or depositions. This would ensure that all parties have an opportunity to fully understand the workpapers, supporting studies and other evidence being relied upon by the other parties. This level of understanding and disclosure was precluded by the circumstances of this proceeding.

One indication of the problem is the fact that there is remarkably little overlap in the details discussed in the simultaneous testimony filings by the non-Company parties on March 23. For instance, a large part of Mr. Horii's testimony is focused on the Company's 2017 Reserve Margin Study, which I decided not to discuss, because I didn't have time to examine the supporting data, nor an opportunity to ask questions about it.

Similarly, neither Mr. Horii nor I had a chance to fully examine changes the Company made to its expansion planning model, or to analyze how those changes affected the PROSYM inputs and outputs. I briefly touched upon a few aspects of these changes in my testimony, but due to time constraints I was not able to fully investigate them. The lack of more discussion of the impact of these changes on the avoided energy cost estimates does not imply a lack of relevance or significance. Rather, it demonstrates one of the problems with the Company's "dramatic change in approach" in this proceeding.

Q. CAN YOU EXPLAIN HOW CHANGES TO THE COMPANY'S EXPANSION PLANNING MODEL AFFECT THE AVOIDED ENERGY COSTS?

A. Yes. The "Base" and "Change" expansion plans are fundamental to the DRR method. The generating units that are assumed to exist, and the extent to which demand side management will be used to accommodate peak demands, the extent to which firm capacity will be purchased, and the extent to which new generating units will be acquired, affects the inputs used in running PROSYM. In turn, these inputs help determine the hourly PROSYM outputs, which determine the proposed avoided energy rates.

Yet, changes to the expansion planning model are not even mentioned by Mr. Horii. I confirmed this by searching for the word "expansion" and I only found this word used in the context of his past experience and qualifications. This is not a criticism of Mr. Horii, nor a suggestion he might have failed to recognize the importance of this issue. Rather, I am using this example to demonstrate that it was not possible for the non-Company parties to fully investigate and respond to the "dramatic changes" included in the Company's filing.

Accordingly, I continue to believe it would be better to explore these issues in a procedural context that provides ample opportunity for discovery, and which encourages the parties to work collaboratively, in an effort to reach a consensus on as many of the technical issues as possible.

Q. DR. LYNCH IMPLIES YOUR TESTIMONY MERELY RESTATES SUGGESTIONS AND RECOMMENDATIONS FROM YOUR TESTIMONY IN THE COMPANY'S 2017 PROCEEDING. IS THIS TRUE?

A. No. Of course, my testimony is largely consistent with my testimony last year, and I have repeated some of my criticisms and suggestions. However, my testimony in this proceeding has emphasized changes to the Company's circumstances since last year – including cancellation of the nuclear construction program and the associated increase in fossil fuel-related risks – and proposed changes to the Company's tariffs. More specifically, I recommended against these proposed changes:

- Reducing the capacity rate on the PR-2 tariff to zero;
- Reducing energy rates despite circumstances where heat rates have increased.
- Removing time-related price signals.
- Eliminating standard offer rates for non-solar generators larger than 100 kW.
- Basing rates on a generic solar profile.
- Basing rates on a sub-optimal "Base" expansion plan that does not minimize revenue requirements.

With the possible exception of the last item, these are all new recommendations, related to the dramatic changes proposed by the Company in this case. As to the final item, last year I expressed some concerns regarding the importance of correctly optimizing the "Base" expansion plan in the DRR method. However, this problem is much more serious in this proceeding, because the Company has made extensive changes to its expansion plan in an apparent reaction to cancellation of the nuclear units. This strongly suggests the need to revisit this issue.

Admittedly, some of my recommendations are similar to last year, like this one:

> I recommend the Commission require the Company to collaboratively work with ORS and other interested parties to develop higher, more accurate QF rates. This can be accomplished by modifying the inputs and assumptions used in the DRR analysis, to more accurately analyze and minimize the revenue requirements under each scenario.[2]

While this recommendation was not implemented, I think the subsequent experience confirms it had merit. I believe everyone would have benefited from a more flexible, collaborative effort to discuss and resolve QF rate issues without narrow time constraints.

2 Direct Testimony of Ben Johnson, Docket No. 2017-2-E, Page 93.

Among other benefits, a more open and collaborative process, with ample opportunity for discovery, information sharing and discussion, would have provided the solar industry with a better opportunity to understand the Company's concerns about the impact of rapid growth in solar generation, and it would have provided the Company with a better opportunity to understand the solar industry's suggestions for how accommodating this growth can help reduce the revenue requirement and reduce risks for retail rate payers.

Perhaps this lack of two-way communication is one reason why the Company developed its DRR calculations using expansion plans that effectively ignore solar capacity that is already in the Company's interconnection Queue, as well as capacity that will soon be added to the Queue. Accordingly, I offered a similar recommendation near the end of my direct testimony in this year's proceeding:

> I recommend that the Commission establish a process to fully consider the issues discussed in this testimony, and to encourage the Company to work collaboratively with ORS and other interested parties in an effort to reach a consensus on as many of the technical issues as possible. The goal should be to develop stronger, more precise hourly price signals, consistent with the earlier discussion in my testimony. This can be accomplished by modifying the inputs and assumptions used in the DRR analysis, to more accurately analyze and minimize the revenue requirements under each scenario.[3]

This year's recommendation mentions the need for stronger, more precise hourly price signals, because this issue is growing in importance, and it would benefit from being discussed outside the time constraints of a fuel proceeding. The impact of increased solar

3 Direct Testimony of Ben Johnson, Docket No. 2018-2-E, Pages 128-129.

generation on avoided cost patterns can be anticipated now, using the same computer modeling tools traditionally associated with the DRR approach. It is simply a matter of asking the right questions, and studying the detailed, hourly output from those tools, rather than ignoring that detail and rolling the numbers up into a few broad averages. This would improve QF price signals and help avoid costly mistakes in the generation expansion plan which might otherwise burden retail customers.

Q. DR LYNCH ARGUES THAT PURPA DOESN'T REQUIRE "ANY ELECTRIC UTILITY TO PAY MORE THAN THE AVOIDED COSTS FOR PURCHASES". DO YOU AGREE?

A. Yes. This is consistent with the portion of PURPA I quoted on page 12 of my direct testimony, which requires that QF rates not exceed ""the incremental cost to the electric utility of alternative electric energy."[4] This statutory requirement is consistent with the interpretation recently offered by the North Carolina Utilities Commission that "the goal is to make ratepayers indifferent between purchases of QF power versus construction and rate basing of utility-built resources."[5]

None of the witnesses in this proceeding are suggesting that QF rates should be set at a level that exceeds the incremental cost of obtaining electrical energy from alternative

4 16 U.S.C. § 824a-3(a).

5 North Carolina Utilities Commission, December 31, 2014 Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140, Page 21.

sources. All of the disputes involve how to correctly estimate those costs. In particular, Dr. Lynch proposes to exclude any consideration of the capital-related costs of alternative energy sources. Regardless of the underlying reasoning or logic, this is clearly an extreme position – one that is not consistent with the requirements of PURPA. The Company incurs substantial capital-related costs in order to maintain the ability to use alternative energy sources. Obvious examples include property taxes, insurance, and the salaries of the people who maintain and operate the Company's generating units.

Since these are fixed costs that do not vary directly with how and when each generating unit is operated, they are not included in the PROSYM output Mr. Lynch used to develop his proposed energy rates. Since PROSYM focuses only on running costs, and the proposed QF energy rates exclude costs that are not in the PROSYM output, it is clear that none of these capital-related avoided costs are reflected in the proposed QF rates. Yet, under PURPA, capital-related fixed costs are part of the "avoided" or "incremental" cost of providing electrical energy.[6]

In sum, there is no disagreement concerning the requirements of PURPA. The disagreements concern whether, and how, these requirements are being fulfilled. Dr. Lynch is correct is opining that "QF rates should be set equal to the utility's actual

6 Avoided cost "includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities." See https://www.ferc.gov/industries/electric/gen-info/qual-fac/orders/order-69-and-erratum.pdf

avoided cost" but he is wrong in excluding capital-related costs, including property taxes, insurance, salaries, depreciation, interest and return on equity.

Q. DO YOU AGREE WITH THE CLAIMS DR. LYNCH MAKES AT PAGE 36 CONCERNING "INCREMENTAL SOLAR"?

A. No. He argues that "incremental solar beyond the 865 MWs of solar capacity already under contract does not alter [SCE&G's] resource plan and, therefore, the difference in revenue requirements is zero."[7] This bold assertion is not supported by any of the workpapers or other documentation provided by the Company. We were provided dozens of files related to the development of its "Base" expansion plan, yet none of these files consider the impact of adding additional solar capacity. Not only has the Company not adequately modeled solar growth, some of the changes it made to its "Base" expansion plan are sub-optimal given the growth of solar. For instance, the Company has not included additional DSM or power purchases that are specifically targeted at unusually cold winter mornings. Because the "Base" expansion plan excludes or ignores these types of opportunities (as with the modeling that was done in this proceeding), the avoided costs that are calculated using the DRR method will be underestimated.

In general, solar provides energy during daytime hours throughout the year. This makes it feasible to avoid the running costs and capacity-related costs of alternative energy

7 Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, Page 36.

sources. To accurately model the full extent to which costs can be avoided, it is necessary to refine the resource mix to ensure there is enough flexibility to take full advantage of the benefits of solar, while also recognizing its limitations – solar energy isn't produced before the sun rises or after it sets.

The expansion planning model used by the Company in last year's proceeding estimated the reduction in revenue requirements associated with adding more solar in a simplified way, by assuming the Company would avoid incremental purchased power costs. That opportunity for cost savings was somewhat constrained by the assumed addition of the nuclear units, but (appropriately) the model assumed larger power purchases if the nuclear units were postponed or canceled. If the Company had simply used that same approach to its current circumstances (reflecting cancellation of the nuclear units) it would have shown additional solar reducing the need for purchased power, thereby avoiding a significant amount of capital-related costs.

Admittedly, last year's modeling effort could be improved upon. In particular, it would be better to refine the model by taking into account the opportunity to purchase power on a targeted basis that focuses on specific hours (like early morning hours around sunrise, and early evening hours around sunset) when demand tends to be strong enough to justify some power purchases, but solar (in the absence of storage) cannot fully meet the need. Logically, this sort of targeted purchase should be less costly than purchasing power on an unrestricted "on demand" or "as needed" basis, since it leaves the seller free to sell firm energy to other buyers during other hours of the day.[8] Similarly, in the context of additional solar, the model could be further improved by including inexpensive Demand Side Management or other "peak clipping" resources that are narrowly targeted at unusually cold winter mornings.[9] This type of narrowly targeted resource is less costly than purchasing peaking capacity. Including it in the resource plan would further reduce the revenue requirement and will improve the accuracy of the avoided capacity cost calculations.

While further analysis is needed, I am confident that incremental solar beyond 865 MWs of solar capacity will significantly affect the optimal resource plan, and the resulting difference in revenue requirements will be substantially more than zero. Stated another way, an appropriate, unbiased modeling effort will confirm that adding more solar provides the Company with opportunities to reduce its revenue requirements, thereby avoiding costs that are not included in the PROSYM output, but should be reflected in the QF rates.

8 The potential cost savings from this type of purchase will become more significant if the daily peak shifts to the late afternoon or early evening.

9 SCE&G 2017 Reserve Margin Study, Page 2.

Q. AT PAGE 37 DR. LYNCH STATES A DISAGREEMENT WITH YOUR TESTIMONY CONCERNING PROSYM. CAN YOU BRIEFLY RESPOND?

A. Yes. Dr. Lynch apparently misunderstood my testimony. I did not claim it was inappropriate to use PROSYM. Rather, I provided a balanced discussion of some of the advantages and disadvantages of this type of model. To the extent I criticized the Company's decisions concerning PROSYM, I was simply expressing my disappointment that the Company did not provide the Commission or interested parties with more of an opportunity to examine the PROSYM output. To fully understand and explore some of the issues discussed in my testimony – particularly the impact of additional solar and the need for stronger, more precise hourly price signals, it would be helpful to have detailed hourly output from all of its PROSYM runs available for analysis and discussion.

Q. AT PAGES 37-38 DR. LYNCH OFFERS SOME COMMENTS CONCERNING YOUR COST ESTIMATES. CAN YOU BRIEFLY RESPOND?

A. Yes. Dr. Lynch is apparently confused about the relevance of these cost estimates. I provided them not as an alternative to calculations developed using PROSYM or the DRR method, but rather as a way communicating more clearly the potential magnitude and significance of the issues discussed in my testimony. For example, Dr. Lynch acknowledged that, under PURPA, avoided capacity costs:

> are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.[10]

Yet, he failed to provide any allowance for these costs in his proposed QF rates, and he did not develop any estimates of avoided capacity costs which could be used to rectify this omission. My cost estimates demonstrate this is a very serious omission, and they clarify that the omission can be disaggregated into two categories – the portion of the capital-related costs that relate to the ability to provide energy during peak hours (typically estimated based upon the cost of owning a Peaker) and the portion that relates to the ability to burn fuel more efficiently than a peaker (benefiting from the lower heat rate of an intermediate or base load generating unit). Both types of capital-related costs are required in order to have "the capability to deliver energy." The former category is primarily relevant to a small number of peak hours, while the latter category is potentially relevant to a wider range of hours across the year. Both types of avoided cost have been excluded from the Company's QF rates in their entirety (but should not have been).

In sum, my avoided cost estimates are relevant because they help explain and quantify this categorical distinction, and they quantify and communicate the potential significance of the failure to estimate these costs, or to include them in the proposed QF rates.

10 Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, Page 4 (citing Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980)).

Q. AT PAGES 38-39 DR. LYNCH OFFERS SOME COMMENTS CONCERNING YOUR TESTIMONY ABOUT FUEL-RELATED RISKS AND THE CANCELED NUCLEAR UNITS. CAN YOU BRIEFLY RESPOND?

A. Dr. Lynch has not offered any disagreement with any of the factual information I provided in this section of my testimony.[11] While he defends his natural gas price assumptions (which I did not criticize), he also admits "future natural gas prices are uncertain" which is the key point. Importantly, he does not dispute the fact that the Company put great emphasis on fuel risks when defending continued construction of its nuclear construction program, nor has he disputed the fact that the Company is now ignoring these same risks when developing its proposed QF rates.

It is worth noting that he did not dispute my conclusion that, when considering ratepayer "indifference," there is an important difference between the risks customers are exposed to when electricity is generated using fossil fuels, and the much lower risk exposure associated with the Company's hydro facility or purchases from a QF at a known price that is fixed in advance. As I explained in my direct testimony:

> All else being equal, a customer will prefer a guaranteed fixed price to a mere estimate of what they might end up paying. To leave a customer indifferent between a renewable QF energy source at a guaranteed fixed price, and a fossil fuel source it is necessary to add a risk premium to the former option before attempting to draw any meaningful conclusions about which technology is preferable from a customer perspective.[12]

11 Direct Testimony of Ben Johnson, Docket No. 2018-2-E, Pages 51-88.

To be clear, I am not asking the Commission to increase the QF rate to reflect this difference in risk. Rather, I am offering this risk difference as an additional factor to be considered when the Commission is resolving other disputed issues in this proceeding – for example, whether to exclude capital-related costs, and whether to estimate avoided energy costs using the previously approved methodology and expansion planning model rather than the new model used by the Company in this proceeding.

Q. AT PAGE 41 DR. LYNCH DISAGREES WITH YOUR DISCUSSION ON PAGES 88-95 CONCERNING STRONGER, MORE PRECISE PRICE SIGNALS. CAN YOU BRIEFLY EXPLAIN THIS DISAGREEMENT?

A. Yes. He explains his disagreement as follows:

> PURPA requires SCE&G to purchase the power produced by any and all QFs that desire to sell power at the Company's avoided cost. SCE&G is prohibited by law from turning away less efficient QFs so the use of avoided costs is not a good vehicle to enhance competitive markets.[13]

His disagreement is primarily contained in the latter half of his second sentence – whether more precise avoided cost-based prices provide a good vehicle for improving competitive outcomes. I will explain in considerable depth why he is mistaken about this, because this particular dispute goes to the heart of some of the most misguided aspects of the Company's proposed changes to its QF tariffs: the proposal to segregate

12 Ibid, Page 56.

13 Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Page 41.

solar production from other forms of energy production, the proposal to eliminate capacity payments, and the proposal to change from Time of Day pricing to a uniform "all hours" kWh rate.

To be clear, I agree the Company does not have the option to refuse power generated by competing firms. Nor, should the Company be allowed to keep competing firms out of the market by reducing the price below avoided cost. Federal law requires the Company to purchase QF power at prices that are determined by state regulators – not by the monopolist. QF rates are supposed to be based upon avoided cost, to ensure that over the long term retail customers pay no more than what they would have paid if all of their power had continued to be supplied by the utility.

Similarly, I agree that PURPA does not require someone to decide which competitors are less efficient, nor does it provide any mechanism to "turn away" these less efficient firms. Instead, the competitive process is supposed to determine which firms succeed and which ones fail, just as it does in other parts of our market-directed economy. Consider what happens in a competitive agricultural market. All farmers receive a similar price for their production, and all are free to produce as much as they want. Hence, success or failure largely depends on their decisions – which crops they plant, the timing of when they plant, how frequently they fertilize, what fertilizers they use, the extent to which they irrigate, how and when they harvest their crops, and so forth. Every firm makes slightly different decisions, and some decisions are better than others.

In competitive markets, winners and losers emerge over time, with inefficient firms earning less than their cost of capital, and eventually going out of business. The most efficient firms expand and thrive, and other firms attempt to emulate their success – adopting their innovations and trying to match their decision-making prowess. This is fundamentally different from what happens in a monopoly market, where the monopolist is shielded from competition by legal or other barriers to entry, which enable it to potentially expand and thrive, regardless of how badly mistaken some of its decisions turn out to be, and regardless of how much those mistakes harm consumers and society as a whole.

PURPA envisions a hybrid market structure, where electrical distribution (and to a lesser extent transmission) continues to function as a monopoly, but competition is encouraged in power generation. Independent power producers are allowed to enter the market and produce as much electricity as they want – provided they use small generators and specific technologies, like hydro, solar, biomass, geothermal, and wind. This creates a more competitive environment, it helps diversify our energy supply, and it reduces exposure to the risks associated with fossil fuels.

While PURPA relies on competition to achieve many of its goals, it retains a crucially important role for monopoly regulation – determining the prices to be paid by the monopolist to its competitors. The pivotal question, then, is what is the point of regulating QF rates? I believe answering this question explains why avoided costs provide a good vehicle for encouraging entry into the power generation market, and achieving the intended goals of PURPA without adverse consequences to retail customers or society as a whole.

Q. WHAT ROLE DO PRICES PLAY IN COMPETITIVE MARKETS?

A. Their most fundamental function is to provide information to market participants. Prices help consumers decide how much they can afford to consume and they help them optimize their consumption decisions – how much to purchase of one item rather than another. Prices play a similar role for producers – helping guide their decisions concerning how much to produce of one item or another, how and where to invest their capital, and what inputs to use in the production process.

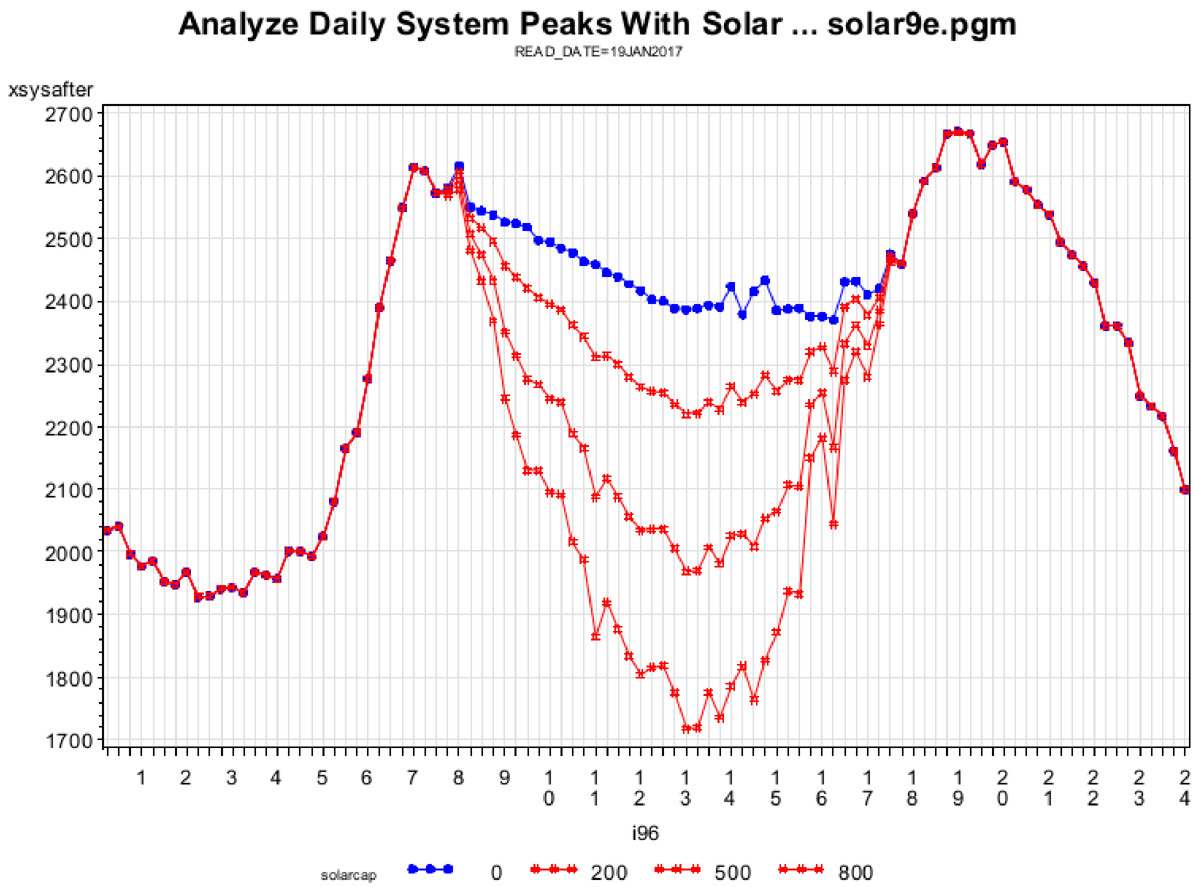
I believe – and I think most economists would agree with me – that the information embedded in prices is crucially important in explaining why well-functioning markets are so successful at achieving societal goals. In fact, history has repeatedly demonstrated that a well-functioning market can be more successful at accomplishing many societal goals than a system with greater centralized control, even when that system is attempting to directly advance those same goals. This has repeatedly been demonstrated when countries have arbitrarily constrained specific prices, in an attempt to make them more "affordable." The inevitable end result is that too little is produced, rationing becomes necessary, and people end up worse-off than if prices had continued to serve their informational function, encouraging more production of the items that are most desired by consumers. Similar problems occur throughout centrally planned economies – bureaucratic control over economic decision making inevitably breaks down, despite the best efforts of the decision makers, if price signals fail to adequately and accurately guide production and consumption decisions.

Experience has repeatedly shown that freely functioning markets with strong, accurate price signals help achieve societal goals, because of their vital role in helping to achieve the "wisdom of crowds." With effective competition, buyers and sellers interacting in the marketplace function like an "invisible hand," increasing efficiency, encouraging innovation, and improving economic wellbeing throughout society.

Q. CAN AVOIDED COST-BASED QF RATES PLAY A SIMILAR ROLE?

A. Yes. Utility regulation often works best when it emulates the most beneficial, successful attributes of competitive markets. I believe the Commission would be well-advised to consider the example of well-functioning prices in competitive markets, and in particular the crucially important role that accurate price signals provide to market participants.

To demonstrate why this is true, consider the potential problems associated with a "Duck Curve" as illustrated in the graph below, from the Company's filing.[14]



The demand for electricity is illustrated by the top line, including the blue portion which shows the amount of electricity customers use during daytime hours, absent solar production. An initial peak occurs around 7 am, and a slightly higher peak occurs around 7 pm. The lowest level of demand occurs in the middle of the night around 3 am. A

14 Exhibit No.___(JML-3), Page 2 of 10.

broad, shallow dip in demand occurs during the day, since this is January, there is no need for air conditioning, and the need for heat diminished as the day warms up.

The light red lines in the middle of the graph simulate what happens to the rest of the system as 200, 500 and 800 MWh of solar energy, respectively, are provided during the hour of maximum solar production. To be clear, these numbers do not represent the amount of installed solar capacity. To achieve this much solar energy on a typical winter day would probably require more installed capacity – perhaps as much as 1,800 MW, in the case of the lowest line.

As more solar energy is brought into the resource mix, potential "problems" emerge. Some of the output of the existing baseload units will be displaced by lower-cost solar energy. This will drive down (and be reflected in) the avoided cost calculations, causing those units to be operated below their optimal rate of output (typically near 100% of capacity). This isn't necessarily a problem, except from the perspective of the owner of those units, since it reduces the economic viability and usefulness of those legacy investments. Similarly, there may be problems with the "ramp rates" and other operating characteristics of some of the older baseload units, since they don't have a lot of operational flexibility – making those investments appear less attractive than when they were first made.

In a monopoly-controlled market, the easiest way to avoid all of these “problems” is to simply not add much solar capacity. This “solution” avoids making the legacy investments appear less useful and obviates any need to take these investments out of the rate base after 30 or 35 years, rather than continuing to use them for 40 or 50 years. While this “solution” may appear attractive from the perspective of a system planner or a monopolist, it would not be economically efficient. In contrast, the competitive solution would continue to add solar energy until avoided costs are driven so low that further investments aren't worthwhile. In effect, granular prices convey accurate cost information to all market participants, so the quantity of electricity produced and the quantity consumed can adapt to actual costs as they evolve over time. This encourages an efficient rate of adoption of new technologies, including storage, and it avoids inefficient investment decisions.

Q. CAN STRONGER, MORE PRECISE RATES DRIVE DOWN AVOIDED COSTS DURING HOURS WHEN THE SUN ISN'T SHINING?

A. Yes. Consider again the example in the graph above. In the absence of solar production, the lowest cost time to produce power is in the middle of the night, when demand is low. However, at least on this particular day it costs more to produce power at 8 am or 7 pm than it does in the middle of the day. Furthermore, this hourly cost pattern will change as more solar energy is produced. The changing patterns will be reflected in the hourly avoided cost estimates produced by PROSYM avoided cost estimates, but some sense of the changes is conveyed by the pattern of light red lines in the above graph.

As more solar is added to the mix, and costs are driven down in the middle of the day, it will become increasingly worthwhile to shift some of that electricity from the middle of the day to later in the evening, or the next morning. This can be accomplished through hourly price signals which reflect the changing pattern of costs over time. For instance, as low cost solar energy becomes more abundant, price-sensitive consumers (especially large, energy-intensive industrial consumers) may respond by shifting some of their usage from morning and evening hours (when costs are higher) into the mid-day hours (when costs are lower). Some industrial customers may decide to install storage to given them even more flexibility in responding to these cost differences.

The end result is to drive down costs even when the sun isn't shining. As solar energy becomes more abundant, avoided costs will initially decline in the middle of the day – creating an opportunity to shift some usage away from hours when costs are higher. While the hourly patterns will be different in the summer, the same principles apply – if appropriate prices are adopted, QF competition can effectively drive down costs and retail rates even when the sun isn't shining.

To fully accomplish this, the actual pattern of avoided costs cannot be submerged within a year-round "all hours" QF rate, as the Company has proposed. With granular price signals, QF's are given an opportunity (and incentive) to respond to hourly cost patterns which apply within each season. With stronger and more precise price signals, the opportunity and incentive for QF responses to those signals become stronger, and the benefits to society become larger. Well designed, granular prices benefit competitors and society, by encouraging better investment decisions, more efficient operational decisions, and more effective competition.

Granular pricing may sound administratively challenging, but in reality the PROYSM computer model already develops 8,760 hourly avoided cost estimates for each scenario and each year that is modeled. The Company did not include any of this hourly cost detail with its testimony, and it hasn't provided it to the parties in this proceeding, but this information can be used to develop granular QF rates.

Q. CAN YOU PLEASE RESPOND TO THE COMMENTS DR. LYNCH MAKES AT PAGE 41 CONCERNING JOINT AND COMMON COSTS?

A. Yes. Dr. Lynch is mistaken if he thinks I used the term “markup” to imply a payment above avoided cost. Rather, I was using the word “markup” to convey the idea that prices may need to be higher than short-run variable cost, or running costs included in the PROSYM output. This is necessary to ensure recovery of fixed costs – the portion of total avoided costs that is not included in the PROSYM output. The essence of this reasoning was explained in this passage:

> in markets (like electricity) where joint and common costs are pervasive, total costs cannot be recovered using pure marginal cost based prices. Instead, prices must include a markup above marginal cost, to provide a mechanism for the recovery of joint and common costs. The cost recovery pattern is clear and consistent across all types of markets where joint costs exist: recover the variable direct costs incurred by producers – short run marginal costs – plus a contribution toward their otherwise unrecoverable indirect, joint and common costs.[15]

The remaining discussion in my testimony is rather technical, showing how joint and common costs are recovered under a variety of different circumstances, and perhaps Dr. Lynch found it somewhat confusing. However, nothing in that discussion was intended to suggest or imply that a markup above avoided cost is needed. I was attempting to explain why QF's should be paid more than just the short-run variable costs they cause to be avoided (the fuel that is not burned when QF energy displaces energy that would otherwise have been purchased or generated using one of the utility's existing generating units). Under PURPA all of the costs that can be avoided should be considered – not just fuel costs. Clearly, this includes capital-related costs that need to be incurred in order to have the ability to burn fuel or generate electricity. While these capital-related costs can be viewed as fixed or unavoidable in the short-run, they are nevertheless highly relevant to this proceeding, since they can and will be avoided as more solar energy is provided by QF's.

15 Direct Testimony of Ben Johnson Docket No. 2018-2-E, Pages 105-106.

Q. CAN YOU PLEASE RESPOND TO DR. LYNCH'S COMMENTS AT PAGE 41 CONCERNING SUMMER AND WINTER PEAKS?

A. Yes. Dr. Lynch's reasoning is reproduced below:

> If SCE&G has to build a combined-cycle unit to meet its winter peak, but which also satisfies the need for summer capacity, then the fixed costs are incurred. In contrast, adding solar capacity, which only has an impact on capacity in the summer, does not avoid any of those fixed costs.[16]

There are three reasons why this line of argument is flawed.

First, there is no evidence that SCE&G will ever have any need "to build a combined-cycle plant to meet its winter peak" or that this would be an appropriate, cost-effective choice. To the contrary, there are better, less costly options for accommodating the infrequent, relatively short duration peaks that sometimes occur during cold weather. These options are much more logical, and less costly, than building a new combined cycle plant. Many of these options are classified as demand side solutions – which is particularly apt, since the Company's concern with meeting its winter peaks is primarily a demand-side issue (uncertainty concerning how customers will respond to severe winter weather conditions). Demand-side options include the Standby Generator Program, Interruptible Generator Program, Real Time pricing, Time of Use rates, and a Winter Peak Clipping Program.[17]

16 Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Pages 41-42.

17 SCE&G 2018 Integrated Resource Plan, pages 15-16.

Second, the Company is summer-peaking, not winter-peaking. This was explained in the Company's 2017 Integrated Resource Plan:

> SCE&G usually peaks in the summer as seen in the following chart. This is reasonable for several factors. First, the climate in SCE&G's service area is generally hotter in the summer than colder in the winter in the sense that kWh sales are about 15% higher in the summer than winter. Second, the penetration of air-conditioners among SCE&G's customers approaches 100% since there are no real substitutes for electric air-conditioners at present. Finally, a large number of electric customers heat their homes and/or businesses with natural gas. Results of the peak demand forecast methodology used herein show that the general pattern of higher summer peaks relative to winter peaks will continue.[18]

Similar language appeared in earlier editions of the Company's IRP.[19] While some of this language was removed from the 2018 IRP, the underlying facts and logic continue to be valid and applicable, and the Company's system continues to be primarily summer-peaking. This was visually demonstrated by the four graphs included in my direct testimony at pages 111-114. It is worth noting that Dr. Lynch has not disputed any of the data shown in these graphs, nor did he attempt to rebut the conclusions I drew from these graphs, including this one:

> The Company is primarily a summer-peaking utility, the demand for electricity is generally stronger in the summer than in the winter, and both common sense and economic theory tell us that capacity costs should mostly be recovered from customers who are using electricity during high demand periods in the summer...[20]

18 SCE&G 2017 Integrated Resource Plan, page 3.

19 See, for example, SCE&G 2015 Integrated Resource Plan, pages 3-4.

20 Direct Testimony of Ben Johnson, Docket No. 2018-2-E, Page 114.

Third, although solar capacity is particularly beneficial during the summer – because that is when peak capacity needs are the greatest – solar capacity is also beneficial (and helps avoids capacity costs) during other parts of the year. Most obviously, solar capacity has a beneficial impact on system capacity during spring and fall daytime hours. Capacity is needed during daytime hours in these shoulder seasons, because this is when coal-fired and other base load generating units are often scheduled for routine maintenance, inspections, and overhauls. This is also the time of year when nuclear capacity is sometimes unavailable, due to refueling. Accordingly, it is simply not correct to assume, as Dr. Lynch does, that "adding solar capacity ... only has an impact on capacity in the summer."[21]

Q. CAN YOU PLEASE RESPOND TO THE TESTIMONY AT PAGE 42 WHERE DR. LYNCH DEFENDS PAYING DIFFERENT RATES TO SOLAR AND NON-SOLAR GENERATORS?

A. Yes. Dr. Lynch never attempts to refute the reasoning I offered, that different technologies can all be paid the specific costs they actually avoid, using the same QF tariff, provided it reflects hourly and seasonal cost patterns. If a solar QF provides power during hours (like summer afternoons) when avoided costs are high, the rate it receives should reflect that benefit. Similarly, if some of its power is provided during hours when avoided costs are lower (like mid-morning on a winter day) the QF rate should be lower, to reflect that fact.

21 Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Pages 41-42.

There is no need to discriminate between different technologies. Wind, hydro, biomass, cogeneration, and other qualified technologies all have different operating characteristics, yet they can all be appropriately compensated using a single technology-agnostic tariff, if the tariff adequately reflects the hourly and seasonal pattern of avoided costs. This is already being accomplished with the existing QF tariff, although further improvements and refinements could be achieved by increasing the degree of granularity – as I just discussed.

Q. WHY IS A TECHNOLOGY-AGNOSTIC APPROACH BETTER?

A. One reason is that there are many different technologies, each with different characteristics. Attempting to anticipate all of the potential technologies that could be used by a QF, and tailoring a specific rate to match the characteristics of that technology is a cumbersome approach that is fraught with difficulties. Assumptions that are appropriate for one hydro plant may not be as accurate, or appropriate, when applied to a different hydro plant. The same is true for cogeneration plants, wind generators, and other technologies. Each plant will have its own unique characteristics – some of which won't be determined until the project is actually constructed and operated. In the case of a cogeneration plant, for example, the volume and timing of electrical output may be intertwined with the unique operating characteristics of the "host" manufacturing or other industrial process.

A second problem with technology-specific rates is that this approach will inevitably tend to be backward-looking. The characteristics of new technologies are – by definition – not well known or well understood. Requiring technology-specific rates to be adopted or negotiated before a QF is allowed to experiment with a new technology will inevitably impose additional regulatory uncertainty and costs, which will discourage innovation and competitive risk taking.

A third problem with technology-specific rates is the high risk of inadvertently discriminating for or against particular technologies, and the competitors interested in pursuing those technologies. A technology-agnostic approach is more likely to provide a "level playing field."

Q. DO ALL SOLAR QF'S HAVE THE SAME CHARACTERISTICS?

A. No. For instance, the pattern of hourly output will depend on whether the facility tracks the sun, or a fixed array is used. Output can also vary depending on other factors, including the specific geographic location. Comparing data from different weather stations, it is apparent that every location has its own unique micro-climate. Although differences are often very subtle, they do exist. For instance, some potential QF locations may have more cloud cover than others, or the cloud cover might be more frequently experienced in the morning in one potential QF location, and more frequently in the afternoon in a different location.

Q. ARE INDIVIDUAL NEGOTIATED RATES THE BEST WAY TO DEAL WITH DIFFERENT QF CHARACTERISTICS?

A. No. Negotiated rates can sometimes be useful in dealing with unique circumstances, but they are not a viable alternative to well-designed, technology-agnostic standard offer tariffs. Granular standard offer rates that reflect hourly and seasonal avoided cost patterns are well suited to all technologies. They allow each QF to receive payment consistent with its actual output characteristics and the corresponding level of avoided costs. Standardized, granular rates also allow the QF to anticipate how their revenues will vary depending on each project's specific technology, location, and other details that are within the QF's control. In contrast, with negotiated rates some of the responsibility for analyzing these issues will lie with the utility. This will make the negotiations more complicated, and potentially more acrimonious. In addition, a circularity problem could arise: the offered rate may depend on the project location, technology and design, but decisions concerning the optimal location, technology and design may depend on what rate will apply (and what revenues will be generated) under each potential variation.

It is also important to remember that utilities may not be eager to co-operate with QF's during the negotiating process, and they won't always be focused on finding "win-win" solutions. Experience demonstrates that utilities can sometimes be uncooperative or slow to offer information. If a utility chooses to be intransigent, it may be easier for the QF to walk away from the negotiation to pursue opportunities in another state, rather than continuing to pour time and energy into seemingly futile negotiations. The "walk away" option may sometimes seem attractive from the utility's perspective, but it is not attractive from an economic development or public policy perspective.

Q. NEGOTIATED PURCHASED POWER AGREEMENTS ARE COMMON. DOESN'T THIS SUGGEST NEGOTIATED RATES ARE BETTER THAN STANDARD OFFER RATES?

A. No. Even when rate negotiations are successful, those negotiations may reflect the existence of a standard offer rate, or the application of a well-understood and long-established methodology used in preparing the standard offer rate. Even if the QF isn't willing to accept the standard offer rate, it provides a useful reference point. This allows the negotiators to focus on quantifying appropriate adjustments to the standard offer rate, in order to reflect the project's unique characteristics and circumstances.

Without the existence of a standard rate option, QF's may be forced to choose between the time consuming and costly arbitration process (under PURPA, the Commission functions as an arbitrator when negotiations break down) or walking away from the project and investing in another state. Forcing QF's to negotiate rates would make it more costly and burdensome to build QF projects in South Carolina – creating regulatory uncertainty and discouraging investment. Avoiding these uncertainties and barriers to entry is particularly important in the context of emerging technologies, like solar + storage.

Q. WHY IS SOLAR + STORAGE IMPORTANT?

A. Solar + Storage is becoming increasingly viable from both an economic and technical perspective. Academic researchers have been pursuing technological advances, and large investments are being made by manufacturers attempting to drive down costs and expand the market for large-scale batteries. The potential exists for significant cost reductions over the next five to ten years, as a result of intense competition between different manufacturers and different technologies, together with increased economies of scale and continued movement down the "experience curve."

This article excerpt provides some sense of the status of competition between different storage technologies:

> Flow batteries have made strides recently in bringing down costs and improving efficiencies, but they are going to have a tough time competing with the entrenched market leader: lithium-ion batteries.
>
> More than half of the 1,280 MWh of worldwide battery installations on the power grid since 2010 have been li-ion batteries, according to Department of Energy data. Looking at just 2015 and 2016, that share rises to 60%. In the United States, li-ion has an even bigger market share at 78% since 2010 and 97% since 2015.
>
> ...
>
> But it seems that just about every other week, researchers announce advances they say will make flow batteries cheaper, safer and more

> competitive when stacked up against li-ion batteries. There have [also] been more real-world advances, such as Primus Power's recent announcement that it has begun production of a flow battery that the company says can last for 20 years and costs 50% less than conventional li-ion battery systems.
>
> ...
>
> Analysts Eric Selmon and Hugh Wynne concede that li-ion batteries compete with several other commercially deployed battery technologies that have performance characteristics better suited for utility-scale storage.
>
> Flow batteries and sodium sulfur batteries, for instance, have longer discharge times and life spans. [but] li-ion batteries have the momentum of economies of scale and a rapidly declining cost curve behind them.[22]

Discussion at a recent industry conference suggests many experts believe we are already past a "tipping point" that will lead to widespread, large scale deployment of energy storage systems:

> "I think we're at or past that tipping point," responded Andy Marshall, practice director for distributed energy resource management at Landis & Gyr. … On Dec. 1... Tesla turned on a 129-MWh lithium ion battery, the world's largest, to help the nation's fragile electric grid.[23]

Praveen Kathpal, vice president of a storage technology company agreed:

> "The tipping point we see in storage is really meshing with some of the other megatrends facing our industry right now. We have the accelerated growth in renewables, and we also have the electrification of more sectors including transportation."

22 Utility Dive, March 14, 2017. https://www.utilitydive.com/news/despite-technological-advances-flow-batteries-struggle-against-market-gian/437399/

23 RTO Insider, December 11, 2017. https://www.rtoinsider.com/energy-storage-gridconnext-82139/

> Kathpal predicted new storage technologies will break below the current pricing floor for lithium ion. "So, 10 years from now, do I think we'll have a commercially available storage technology that's below $100/kWh? Sure."[24]

The lead research engineer from another energy technology firm was equally optimistic:

> More and more markets continue to value the fast-ramping and bidirectional capability that energy storage provides. And I think as systems continue to decline in cost, we will compete in more and more markets. A lot of the market prices basically clear according to the natural gas price. So it's really just a matter of getting renewables plus storage to below that threshold in more and more places.

However, other participants noted storage costs are currently higher than some other alternatives, like demand-side management, at least in some situations:

> Richard Brody, director of sales and marketing for Lockheed Martin Energy's energy storage unit, said storage is still relatively expensive when compared with energy efficiency and demand response.
>
> …
>
> But he is nevertheless bullish on storage. "In terms of the tipping point – oh yeah, we're passed it. This is a rapidly growing market.
>
> We're seeing very strong growth in interest in doing large solar and wind coupled with storage. Most of the large developers we're working with aren't contemplating any large development of solar – and increasingly wind – without some way to firm it up with a fairly significant storage system."

24 Ibid.

Q. HOW DOES SOLAR + STORAGE FIT WITH THE COMPANY'S PROPOSED TARIFF CHANGES IN THIS PROCEEDING?

A. It doesn't. None of the changes proposed by the Company align as well with solar + storage as the existing QF tariff. The uniform "all hours" rate for solar is obviously not viable, since the QF would receive the same (or less) revenue from a solar project that includes storage than from one that doesn't include any investment in storage.[25] If the negotiated rate option were applicable to solar projects that include storage, that option would also not be viable, because of the problems just mentioned, including the circularity problem. There are a wide range of possible storage configurations, each with different characteristics. Without knowing how much will be gained by storing power at one hour and using it at another hour, it will be impossible to evaluate the pros and cons of the different technologies and other investment options.

Consistent with the intent of PURPA, South Carolina QF's should be allowed to take calculated risks investing in new storage technologies.[26] However, without a reasonable degree of regulatory certainty with respect to how hourly avoided cost differentials will be passed through to QF's, it becomes impossible to meaningfully evaluate investments that allow power to be generated in one time period and sent to the grid in another. Telling a QF that the rate is "subject to negotiation" is no better than saying that the

25 Revenues would actually decline if a battery technology is used, because of the energy losses that occur each time the battery is charged and discharged.

26 Unlike rate base investments, the risks will be borne by the QF's investors, not by retail customers.

potential benefit from investing in storage investments is completely unknown. Adding that sort of regulatory uncertainty on top of all the other risks and uncertainties associated with new technologies will greatly discourage QF investments in storage. In contrast, with technology-agnostic granular QF rates each competitor will be able to make their own decisions about the future trend in storage technology costs, the optimal timing for making storage investments, and all of the other project-specific decisions that need to be made when evaluating a solar project with a 30+ year economic life.

With appropriate QF rates, some competitors may attempt to achieve an "early mover" advantage by obtaining operational experience with storage from the outset of some projects. Others may initially construct a solar-only facility, while planning to add storage once the pattern of hourly avoided cost differentials (as reflected in their contract) increases sufficiently to justify investing in storage. Choosing between these strategies or making other storage-related investment decisions will be nearly impossible if the Company's tariff proposals are accepted in this proceeding – including the change to a negotiated rate environment or the change to a uniform "all hours" rate.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY WHICH WAS PREFILED ON APRIL 4, 2018?

A. Yes.